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David S. Guzy, Chief,
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Dear Mr. Guzy:

The City of Long Beach, as Trustee for the State of California, submits these comments in response to the Supplementary Proposed Rules published February 6, 1998 in 63 Fed. Reg. p. 6113. We continue to support MMS's proposal to use West Coast spot ANS prices for valuation of federal royalty oil in California for non-arm's length transactions. In previous comments we have expressed our reasons as to why West Coast spot ANS prices should be used even for so-called arm's-length transactions.

Spot prices for ANS landed in California are used in many arm's-length transactions. ANS continues to be sold on the West Coast at prices much higher than comparable California crudes or other California crudes when adjusted for quality and location differences. It is appropriate to use ANS to determine the market value of California crude because ANS is the swing crude in California and constitutes a very large percentage of California refinery feedstock.

We are against replacing index pricing based on ANS prices with royalty-in-kind sales. Royalty-in-kind sales can be expected to suffer the same fate as sales of all other California crudes. The sales prices will be below parity with ANS.

There are several reasons why royalty-in-kind sales will not take place at market value. The California crude market is not open and competitive. It is dominated by a few Majors. Those Majors control 65% of production, and over 80% of refining and transportation of crude oil and marketing of gasoline. Private ownership of three heated pipelines in California continues to depress prices for producers because producers do not have access to these pipelines for the purpose of marketing their crude oil. Indeed federal royalty oil in Midway Sunset is tied into the proprietary Mobil heated pipeline. The posters in California and even some non-posting Majors are rarely willing to pay more than posted price for California crudes even while they consistently paid higher prices for closely comparable ANS. This policy cannot be expected to change merely because MMS is selling federal royalty-in-kind crude oil. The result of the Majors' control of the California market and their unwillingness to pay prices above postings is that MMS will not receive market value for any royalty-in-kind sales. Only the non-Majors who are least able to bid a competitive price will be competing for federal royalty-in-kind oil.

Although we are in general agreement with MMS's approach to valuation of federal royalty oil in California, we have, in addition to the objections raised in previous submissions to MMS, objections to some specifics of the proposed supplemental regulations of 2/6/98. Our objections concern the following:

1. Tracing through successive buy/sells (Sect. 206.102(c)(3))
2. transportation cost deduction (Sect. 206.113(b))
3. double deduction for transportation and quality adjustment (Sect. 206.113(a))
4. backdoor rule: allows evidence of purchases at posted price (Sect. 206.103(e)(i))
5. balancing agreements (Sect. 206.102(c)(1) and (c)(2).

1. <u>Tracing Through Multiple Exchanges</u>.

We object to Sect. 206.102(a)(3) which requires valuation under the gross proceeds methodology for federal royalty oil which is sold after serial arm's-length exchange agreements for several reasons. First, as the Task Force report noted (p. 49-50), oil company accounting records do not allow tracing of royalty crude through successive exchanges. (We use the term "exchanges" to refer to both exchanges and buy/sells.)

Second, federal royalty oil cannot physically be traced through successive exchanges. Crudes which are received on exchange for federal royalty oil are commingled with other crudes. In successive exchanges, commingled streams are exchanged for other commingled streams. Tracing the original royalty crude through a series of exchanges of commingled streams of varying volume is an impossibility for the oil companies or MMS.

Third, even if lease production could be traced through a series of exchanges, if there are multiple sales of crude at the end of the series of exchanges, proposed §206.102(c)(3) permits the producer of federal royalty oil to value federal lease oil based on the lowest price received for the multiple sales.

The problem of tracing royalty crude through multiple exchanges is illustrated in Attachment 1 which is consistent with crude oil trading practices in California. We have presented an example of a producer of federal royalty oil in the Midway Sunset Field who simultaneously engages in a number of exchanges one of which involves federal royalty oil and sells both ANS and Wilmington crude oil in Long Beach but at different prices. In the first exchange the producer exchanges Midway Sunset crude for Kern River crude; in the second exchange the producer exchanges Kern River crude for San Joaquin Valley heavy crude (SJVH) in the Bay Area; and in two additional exchanges, the producer exchanges SJVH for both ANS and Wilmington crude in Long Beach. In all of these exchanges the producer incurs a quality location charge. In our example, the producer sells ANS at $18.00 a barrel and Wilmington crude at $17.00 a barrel.

Although the producer cannot trace the hydrocarbon molecules produced at the lease to the sales of ANS and Wilmington crude in Long Beach, the regulations permit the producer to value its federal royalty oil at Midway Sunset by its ANS and Wilmington crude sales in Long Beach. Under the proposed regulations, the producer is entitled to deduct the quality/location differentials incurred in the four exchanges from the sales prices of ANS and Wilmington crude. In our example, the sales price of ANS is adjusted downward to $15.05 and the Wilmington crude is adjusted down to $15.85 to affect the location/quality differentials in the exchanges. Under proposed §206.102(c)(3), the producer of federal royalty oil at Midway Sunset is entitled to use the lowest price, namely $15.05 per barrel, as the value of the federal production of Midway Sunset.

The example illustrates several problems with the regulation. First, tracing federal royalty oil through several arm's-length exchanges is impossible although the regulation permits a producer to fictitiously trace production through a series of exchanges. Second, when a producer has multiple sales of crude (ANS and Wilmington in our example) the regulation permits the producer to value the royalty oil on the basis of the lowest sales price. Third, the regulation permits the producer to deduct from the ultimate sales price all of the location and quality adjustments in the whole series of exchanges, even though the royalty crude is not moved directly to the market in Los

Angeles. We would agree that the cost to transport the Midway Sunset crude directly to Los Angeles is a deductible expense, but the transportation costs in all of the exchanges in our example should not be a deductible expense.

The problems would be further compounded if the federal producer from time to time sold Kern River crude and SJVH crude. The producer would then be free to use the sales prices of Kern River, SJVH, ANS and Wilmington as the price to value the Midway Sunset production.

Proposed Sect. 206.102(c)(3) implicitly assumes that producers will use a series of in/out exchanges in which the same volume of crude is transported through numerous pipelines to a sales point in a series of exchanges. But the reality is that oil companies engage in multiple evergreen exchanges which are not in/out exchanges and involve different volumes of crudes.

2. <u>Transportation From Lease To Refinery</u> (Sect. 206.113(b)).

We agree that a location differential between the lease and the market center is an appropriate adjustment that needs to be made to the index price of the crude. But the cost to move crude from the lease to a refinery, if the refinery is not located at the nearest market center, is irrelevant in almost all cases to determine the value of crude at the lease. Permitting oil companies to deduct the entire transportation cost to move crude from the lease to a refinery would permit OCS producers in California to deduct the entire cost of moving the OCS crude to the Gulf Coast. See Attachment 2. Likewise, the rule would permit a federal royalty owner to deduct the entire cost of moving Permian Basin crude from the Permian Basin to Midwest refineries.

We understand that the reason for Sect. 206.113(b) is MMS's concern that a producer who ships crude only to its refinery would not know the cost to move crude to the nearest market center. The fact that a federal leaseholder might not move any crude from the lease to the nearest market center is no justification for permitting the deduction of transportation costs from the lease to the refinery. At least in California, the costs to move crude from lease to market center can be ascertained from pipeline tariffs. Pipeline tariffs should form the upper limit to deductible transportation costs from the lease to the market center. Even in those cases in which crude is moved to the market center over private pipelines, MMS will be able to establish transportation costs from lease to the market center based upon the information gathered by MMS from Form MMS-4415.

Only in circumstances in which no crude from the area of federal production moves to a market center and where there are no available pipeline tariffs for pipelines that could move crude from the lease to a market center should the transportation to a refinery be deductible. In those circumstances, the refinery would be the nearest market center. In all other circumstances, transportation costs from the lease to a refinery should not be deductible.

3. Double Deduction For Transportation and Quality: Sect. 206.113(a).

Proposed Sect. 206.113(a) provides that if a company disposes of its lease production under an arm's length exchange agreement, it is entitled to deduct costs under Section 206.112(a)(c) and (e). Section 206.112(a) and (c) overlap to some extent with regard to transportation costs. See Attachment 3. The aggregation point referred to in (c) is located between the lease and the market center. Thus, subsections (a) and (c) allow for a double deduction of the cost of moving crude from the lease to the aggregation center. Furthermore, subsections (a) and (e) allow for quality adjustments. See Attachment 3. Thus, subsections (a) and (e) allow for the double deduction of the quality differential as between the crudes at the lease and the crudes at the market center.

4. The Proposed Regulations Open the Door For Valuation Based On Discredited Posted Prices: (Sect. 206.103(e)(2)(i)).

Proposed Sect.206.103(e)(1) permits companies who transport crude directly from the lease to their refineries to apply for approval to use a "market value" at the refinery which does not use an index price. Subsection (e)(2)(i) permits evidence of the costs of acquiring other crudes to establish the market value of federal royalty oil at the refinery. But many crudes are acquired at posted price. Thus, the proposed regulations would permit companies who transport crude directly from the lease to their refineries to apply for approval to use a value based on comparable purchases many of which would be at posted prices. Because the whole thrust of the proposed regulations has been to abolish the reliance on posted prices, we find this provision to be anomalous and objectionable.

5. <u>Balancing Agreements</u>: (Sect.206.10(c)(1)(2)).

A fifth problem with the proposed regulations is the failure to protect against undervaluation when federal royalty crude is sold to a company with which the federal producer has an overall balancing agreement. In an overall balancing agreement, the volumes of crudes purchased and sold are kept even. An overall imbalance on one exchange in favor of Company A will be corrected by an imbalance on one or more exchanges in favor of Company B. The companies to the balancing agreements are not arm's length competitors concerning the absolute price terms in their purchases and sales. If the companies to the balancing agreements are both net purchasers of crude in the United States, they have an incentive for low absolute prices in their purchases and sales. Thus, the absolute prices in the sales of federal royalty oil between companies having an overall balancing agreement with one another are not an indication of the market value of the crude.

Under the proposed Section 206.102(c)(1) and (c)(2), if MMS finds an overall balancing agreement exists, the royalty value of oil would be calculated on the basis of Sect. 206.103 (an index methodology) or the total consideration received, whichever is greater. Our objection is that the proposed rules shift the burden to MMS to determine whether there is an overall balancing agreement between two companies. Under the Supplementary Proposed Rulemaking of July 3, 1997, overall balancing agreements would automatically preclude the use of the gross proceeds methodology and the burden would be on the oil companies to identify when overall balancing agreements exist.

The burden shifted to MMS to identify overall balancing agreements is too great. It is difficult to prove that an overall balancing agreement exists, because many such agreements are not in writing. We fear MMS would not able to fulfill its burden of identifying overall balancing agreements and it should not place itself in a position of so doing.

Some Additional Points

A. Sect. 206.103(a) should specify that the relevant ANS spot price is that for the West Coast.

B. The definition of "Location Differential" Sect. 206.101 ("the value difference for oil at two different points") is too broad and includes differences of quality and location. It should be revised to read: "the value difference for the same quality oil at two different points."

C. The definition of "Quality Differential" is too broad in its inclusion of "and other quality factors." Some lessees may include deductions for alleged "quality factors" which have no impact on the market value of crudes.

D. At the Bakersfield meeting on March 11, 1998, an oil industry representative stated that gravity banks in common carrier pipelines such as the All America Pipeline, were inappropriate to adjust for quality differences between ANS and California crudes. His reasoning was that such gravity banks applied only to California crudes and California crudes are of entirely different quality than ANS.

In fact, the All America Pipeline has carried California OCS, SJV crudes and ANS. The gravity bank on the pipeline thus adjusts for gravity differences between ANS and California crudes. Also, companies exchange California crudes for ANS and use posted price gravity price differentials to adjust for differences in quality between ANS and California crudes in those exchanges.

E. The same industry representative stated that Reuter's and Telerate report ANS spot prices for the West Coast generally and not specifically for California and hence use of such spot price data will not give the spot price of ANS in California.

Platt's reports spot prices for ANS delivered in Long Beach. If Reuters and Telerate are unacceptable, at least Platt's can be used for ANS spot price data.

We hope that these comments are helpful.

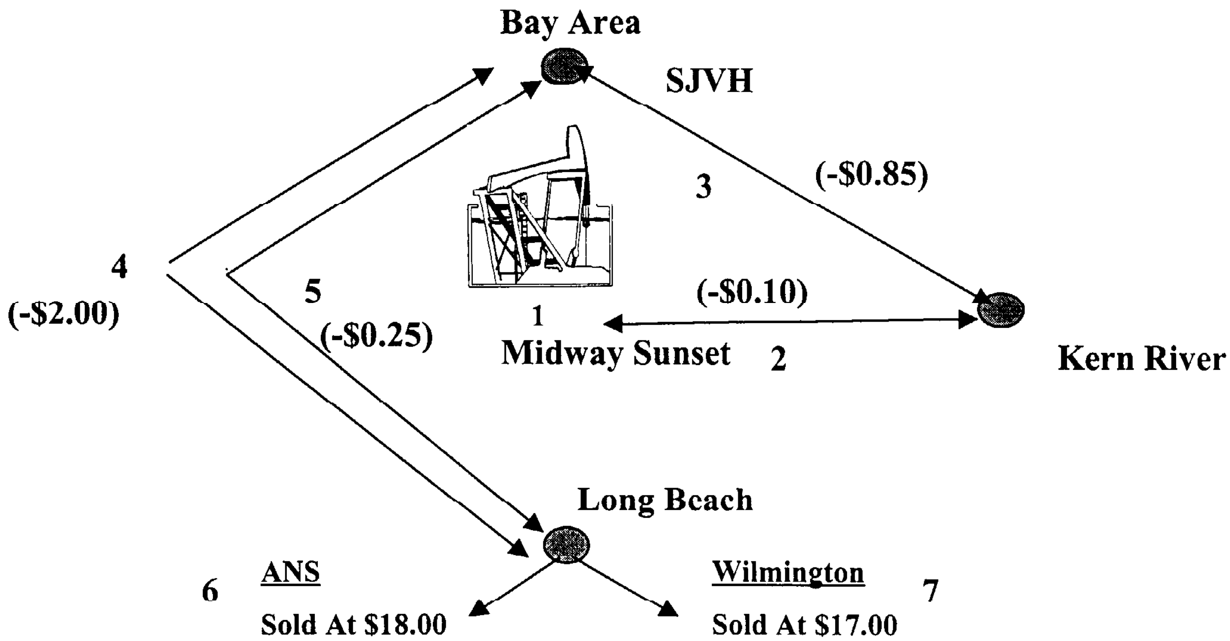
Sincerely,

JAMES N. McCABE
Deputy City Attorney,
City of Long Beach

JNM:pw

C:guzy.ltr

Example of Problems of Tracing "Downstream" Exchanges (Sect. 206.102 (c) (3))



Series of Exchanges Culminating In Multiple Sales

1. Company "A" produces federal royalty oil in Midway Sunset.
2. Company "A" exchanges 10,000 b/d Midway Sunset for 10,000 b/d Kern River and pays $0.10/bl location differential.
3. Company "A" trades 50,000 b/d Kern River for 50,000 b/d SJVH in the Bay Area and pays $0.85/bl location differential.
4. Company "A" trades 25,000 b/d of SJVH for 25,000 b/d ANS delivered in Long Beach and pays a $2.00/bl location quality differential.
5. Company "A" trades 25,000 b/d of SJVH for 25,000 b/d THUMS delivered in Long Beach and pays a $0.20/bl quality differential.
6. Company "A" sells 25,000 b/d ANS for $18.00 per barrel.
7. Company "A" sells 25,000 b/d Wilmington for $17.00 per barrel.

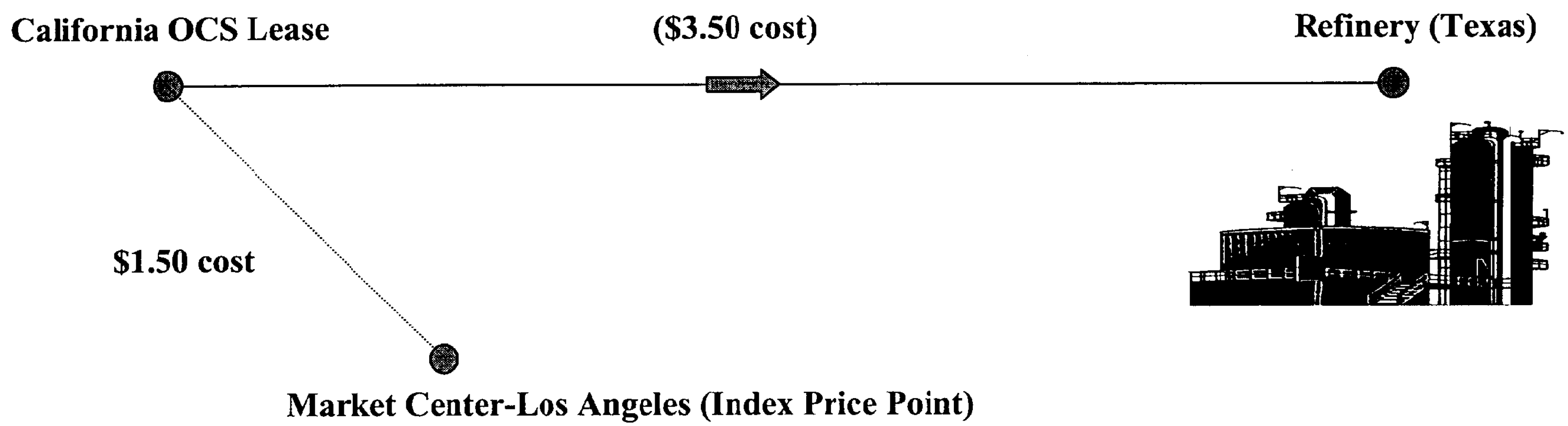
Sect. 206.102(b) permits Midway Sunset lease value to be computed two ways:

ANS Sale	Wilmington Sale
$18.00	$17.00
-$2.00	-$0.20
-$0.85	-$0.85
-$0.10	-$0.10
$15.05	$15.85

Attachment 1

Lease to Refinery Transportation Deduction When Using Index Pricing

Sect. 206.112 (b)



Company A produces OCS oil in California and transports it to its refinery in Texas.

Royalty value for OCS oil is computed on the basis of index value less $3.50, when in fact true market value should be index value less $1.50.

Attachment 2

Excess Deductions Are Allowed Under Sect. 206.113(a)

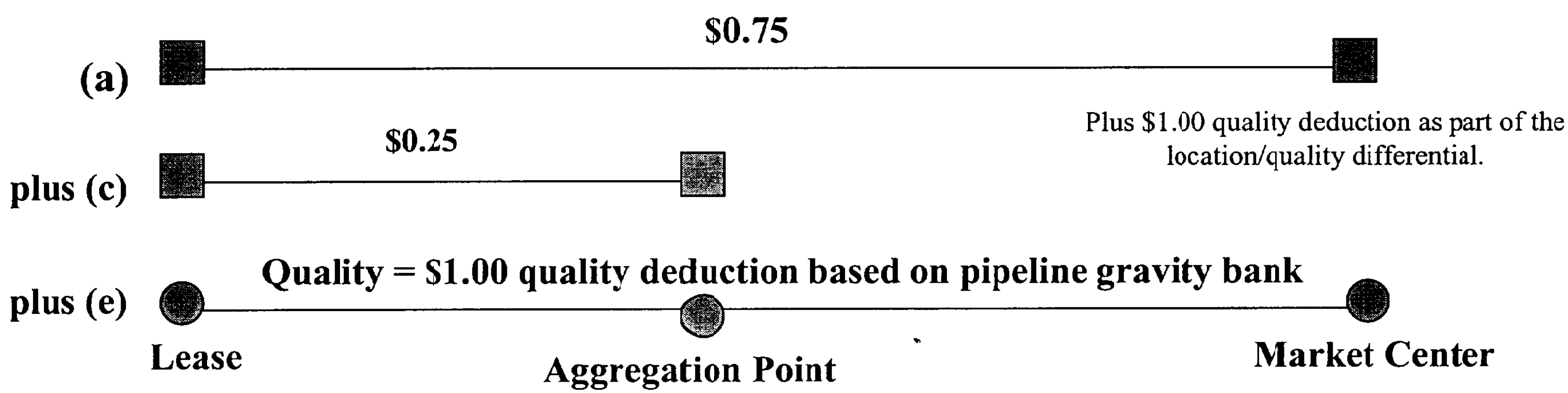
(Index Pricing of Production Disposed of Under Arm's Length Exchanges)

Section 206.113(a) permits deductions for:

(a) = location/quality differential between lease and market center

(c) = actual cost between lease and aggregation point

(e) = quality adjustments



Total Deduction Allowable Under The Rule = $3.00

Total Deduction Which Should Be Allowed = $1.75

(Reflects total quality and location adjustment under (a))

Attachment 3